Appendix B

Revised Non-EGU Budget and Documentation ~~Regarding Corrections to Kentucky'sEGU and Non-EGU Budgets~~

(An electronic version of the NOx SIP Call plan and relevant documents ~~attachments~~ can be found on the Division for Air Quality's web site at: http://www.air.ky.gov/homepage_repository/Public+Hearings.htm.)

EPA January 23, 2004, Correspondence Regarding Fluidized Catalytic Cracking Units (FCCUs) CO Boilers and the NOx SIP Call

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 4
ATLANTA FEDERAL CENTER
61 FORSYTH STREET
ATLANTA, GEORGIA 30303-8960

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DIRECTOR'S OFFICE
DIVISION FOR AIR QUALITY

John Lyons, Director
Division of Air Quality
Department for Environmental Protection
KY Natural Resources & Environmental
Protection Cabinet
803 Schenkel Lane
Frankfort, Kentucky 40601

Dear Mr. Lyons:

As requested, we are providing you with the Environmental Protection Agency (EPA)'s position regarding coverage of carbon monoxide (CO) boilers combusting CO from Fluid Catalytic Cracking Units (FCCUs) under the Nitrogen Oxides (NOx) State Implementation Plan (SIP) Call. The NOx SIP Call includes "industrial boilers" as large non-electric generating units (non-EGUs), but excludes FCCUs, from calculation of required highly cost-effective reductions (63 FR 57356, 57416, October 27, 1998). In the NOx SIP Call preamble and rule, "FCCU" is not defined, but the definition of "boiler" in the final rule (40 CFR 96.2) covers FCCU-CO boilers. Further, the NOx SIP Call large non-electric generating unit (non-EGU) inventory includes some, but not all, FCCU-CO boilers. This resulted in inconsistent treatment of FCCU-CO boilers among the states, with some states including them in the NOx SIP trading program as non-EGUs and some states excluding them from the NOx SIP trading program.

In a series of conference calls, EPA Region 4, along with staff from the EPA Clean Air Markets Division (CAMD), discussed this issue with your staff. At that time CAMD explained that EPA intends to allow each state with one or more FCCU-CO boilers to determine whether all of the state's FCCU-CO boilers are covered, or all of them are not covered, by the NOx SIP Call trading program. The enclosed position paper describes EPA's position regarding FCCU-CO boilers in detail.

Marathon Ashland Petroleum (MAP) in Boyd County, Kentucky, owns and operates the only facility in Kentucky with FCCU-CO boilers of which we are aware. This facility has three FCCU-CO boilers (i.e., 64, 8C-North, and 8C-South), which are allocated a total of 95 allowances under Kentucky's existing NOx SIP Call trading program regulations. Kentucky has elected to exclude all FCCU-CO boilers in the state from the NOx trading program and to remove from its SIP the requirement that such units comply with the program. Because MAP's FCCU-CO boilers are being removed from the NOx trading program, the tonnage of emissions attributable to the FCCU-CO boilers in the NOx SIP Call emissions inventory should be removed and the total amount of NOx allowances allocated for non-EGUs should be reduced.

Under Kentucky's allocation methodology approved into the Kentucky SIP, if the number of NOx allowances assigned to Kentucky changes before the end of an allocation period and the total number of NOx allowances assigned to non-EGUs is reduced, then Kentucky arguably should reallocate the reduced, total number of NOx allowances among the existing non-EGUs in the NOx trading program using the allocation formula and other allocation provisions in the SIP. (See Sections 4 "Methodology for the Allocation and Sale of NOx Allowances" and 5 "Allocation of NOx Allowances" in 401 KAR 51:160: NOx requirements for large utility and industrial boilers in the Kentucky SIP.) In this case, removal of the controlled emissions attributable to FCCU-CO boilers in the NOx SIP Call emissions inventory would result in small reductions of the remaining non-EGUs' existing allocations.

However, the allowances in the existing allocations to non-EGUs were recorded in the Allowance Tracking System on, and have been in the units' accounts since, August 15, 2002. Moreover, some of these allowances may have already been traded.

Under these circumstances, if Kentucky begins the procedures necessary to remove all FCCU-CO boilers in Kentucky from the NOx trading program, EPA will waive, only for the 2004-2006 allocation period, the requirement for Kentucky to determine the controlled emissions attributable to FCCU-CO boilers in the NOx SIP Call emissions inventory and to reallocate the NOx allowances among the remaining non-EGUs. This waiver is contingent upon Kentucky taking the following actions:

1. Remove immediately from the NOx trading program all allowances currently allocated to MAP for FCCU-CO boilers for each year during 2004-2006, and leave unchanged the existing allocations for the remaining non-EGUs for 2004-2006.

2. Complete the procedures for removing all FCCU-CO boilers in Kentucky from the NOx trading program.

3. When the NOx allowance allocations for non-EGUs are updated in 2004 for 2007-2009,

   i. Determine the controlled emissions calculated for MAP's FCCU-CO boilers by examining the 2007 control case portion (which reflects 60% reduction of 2007 uncontrolled emissions) of the NOx SIP Call emissions inventory.

   ii. Decrease the total tons, and the total amount of NOx allowances, for non-EGUs in the NOx trading program by the amount determined in 3.i. above, and allocate the reduced, total amount of NOx allowances using the applicable allocation formula in the Kentucky rule.

4. Each time that allowance allocations for non-EGUs are updated after 2004, allocate the reduced, total amount of NOx allowances for non-EGUs in the NOx trading program,

as determined in 3.ii. above, using the applicable allocation formula in the Kentucky rule.

For further questions regarding this letter, please contact Michele Notarianni of the Region 4 staff at (404) 562-9031.

Sincerely,

Carol L. Kemker for

Beverly H. Banister
Director
Air, Pesticides and Toxics
Management Division

Enclosure

NOx SIP Call Applicability: Carbon Monoxide (CO) boilers combusting CO from the Fluid Catalytic Cracking Units (FCCUs)

BACKGROUND

General

- Some FCCUs use CO boilers (FCCU-CO boilers) to combust and thereby control CO and to produce steam for use at the refinery.
- NOx is produced by the regenerator at the FCCU and by the CO boiler and vents through a single stack.

NOx SIP Call treatment of FCCU-CO boilers

- The NOx SIP Call includes "industrial boilers" as large non-electric generating units (non-EGUs), but excludes FCCUs, from calculation of required highly cost-effective reductions (63 FR 57356, 57416, Oct. 27, 1998).
- In the NOx SIP Call preamble and rule, "FCCU" is not defined, but the definition of "boiler" (40 CFR 96.2) covers FCCU-CO boilers.
- Technical support documents developed for NOx SIP Call final rule (but not developed for NOx SIP Call proposed rules) describe "FCCU" as including the process heater and the regenerator and treat the FCCU-CO boiler as a separate source.
- The NOx SIP Call large non-EGU inventory includes some, but not all, FCCU-CO boilers.
- Part 60, Subpart J (40 CFR 60.101(m)) arguably defines "FCCU" to include the FCCU-CO boiler (i.e., as "regenerator equipment for controlling air pollutant emissions and for heat recovery").
- Treatment of FCCU-CO boilers is inconsistent among States, with some States including them in the SIP NOx trading program as non-EGUs and some States excluding them from the SIP NOx trading program.

EPA'S POSITION

EPA intends to allow each State with one or more FCCU-CO boilers the option of determining whether all its large FCCU-CO boilers are covered, or all its large FCCU-CO boilers are not covered, by the SIP NOx trading program. EPA does not intend to allow States to split the category by including some, but not all, large FCCU-CO boilers in the trading program.

- EPA's position is based on the following circumstances:

  a. The NOx SIP Call includes industrial boilers (as large non-EGUs), but excludes FCCUs, from calculation of required highly cost-effective reductions.

  b. The NOx SIP Call definition of "boiler" covers FCCU-CO boilers.

  c. Technical support documents for the NOx SIP Call final rule (but not included for NOx SIP Call proposed rules) define "FCCU" as not including the FCCU-CO boiler.

  d. The 40 CFR Part 60 definition of "FCCU," which arguably includes FCCU-CO boilers, created confusion over whether FCCU-CO boilers were included as non-EGUs.

e. Treatment of FCCU-CO boilers in large non-EGU inventories and SIP NOx trading programs is inconsistent among States.

- Because of these circumstances, EPA believes each State should have the option of deciding whether to include all large FCCU-CO boilers in, or exclude all large FCCU-CO boilers from, the SIP NOx trading program; EPA intends not to disapprove SIPs simply because they exclude all large FCCU-CO boilers in the State from the trading program.
- EPA recommends that a State may choose to revise its SIP to include or exclude all large FCCU-CO boilers in that State as follows:

    a. To exclude an FCCU-CO boiler currently in, and allocated allowances under, the SIP NOx trading program,[1]

        1. Take back (or do not take action to provide) all allowances allocated to such boiler and remove such allowances from the trading program.

        2. When the allowance allocations for non-EGUs are updated,

            i. Determine the controlled emissions calculated for such boiler by examining the 2007 control case portion (which reflects 60% reduction of 2007 uncontrolled emissions) of the NOx SIP Call emissions inventory.

            ii. Decrease the total tons, and thus the total amount of allowances, for non-EGUs in the NOx trading program by the amount from step a.2.i above.

    b. To include an FCCU-CO boiler currently not in, and not allocated allowances under, the SIP NOx trading program,

        1. Allocate to such boiler an amount of allowances calculated using the same procedures that were used to allocate allowances to the other non-EGUs.

        2. When the allowance allocations for non-EGUs are updated,

            i. Calculate the NOx emissions remaining at the boiler after the NOx SIP Call reduction (a 60% reduction of 2007 uncontrolled emissions) by using the 2007 base case emissions inventory).

            ii. Increase the total tons, and thus, the total amount of allowances, in the NOx trading program tons by the amount from step b.2.i above.

- For questions, contact Dwight Alpern (202-564-9151) or Doug Grano (919-541-3292).

[1] If an FCCU-CO boiler is currently in the SIP NOx trading program but is not allocated allowances because the unit is not in the 2007 control case in the NOx SIP Call emissions inventory, the unit may be excluded from the program by continuing not to allocate allowances and, when allowance allocations are updated, continuing to exclude the unit's emissions from the 2007 control case.

Kentucky Division for Air Quality Identified List of Large ICEs and the 1997 ICE Emissions Submitted as February 22, 1999, Comments on EPA's NOx SIP Call

TABLE IX. Kentucky's Final Determination of Non-EGU Internal Combustion Engines Meeting the U.S. EPA's Criteria for Control

FIPSST	FIPSCNTY/ PLANTID	PLANT/ PLANTID	POINT ID	SEGMENT	SCC	EPA POD #	1997 TYPICAL OZONE SEASON DAILY NOx EMISSIONS (TONS)	EPA PERCENT CONTROL LEVEL
21	089/ 0033	TENNESSEE GAS PIPELINE CO.	04	13	20200202	22	1.115	90
21	107/ 0134	ANR PIPELINE CO.	02	01	20200202	22	2.197	90
				02			1.863	
			03	01			2.751	
21	197/ 0006	COLUMBIA GULF TRANS CO.	04	01	20200202	22	1.655	90
				02			1.367	
				03			1.397	
				04			1.739	
21	197/ 0013	TENNESSEE GAS PIPELINE CO.	04	30	20200202	22	1.727	90
21	217/ 0034	TENNESSEE GAS PIPELINE CO.	04	03	20200202	22	1.220	90

Louisville-Metro Air Pollution Control District (Jefferson County) ICE Emissions Information for 1995 and 1997

TO MARTIN LUTHER (502) 573-3787

PLANT INFORMATION (Level 1)

Plant Name: TEXAS GAS TRANSMISSION Last Updated by: JHS on 06/07/1996
Type of Inventory: 4
State: KENTUCKY County: JEFFERSON CO (1920) AQCR: 078
NEDS Plant ID: 0223 Emissions Year: 1995 Local Plant ID:
Street Address: 10327 GASLIGHT WAY City: LOUISVILLE, KY Zip Code: 42301-
City Code: 2380 UTM Zone: 16 UTM Easting: 625.5 UTM Northing: 4230.6
Township/Modeling Grid Code:
SIC Codes - Primary: 4922 Secondary: Tertiary:
Principal Product: NAT GAS Employees: 30 Plant Area: 5.0 acres
Plant Contact: DARRELL MORGAN Telephone Number: (502) 688-6957 Engineer: Stephen M. Taylor
Plant Level Comment:

Notes:

(1) VOC emissions derived from operating hours are formaldehyde.
(formaldehyde emissions are also entered under the A1 HAPS point record)

(2) Emission factor units are lbs/oper hr for the entries under the categories of operating hours.

POINT INFORMATION (Level 2A)

Point ID: 01 Local Point ID: Last Updated by: KTI on 04/15/1992
SIC: 4922
UTM Easting: 625.50 UTM Northing: 4230.60 Latitude: - - Longitude: - -
Operating Schedule - Hours per day: 24 Days per week: 7 Weeks per year: 52
Start time: 00:00 Ending time: 24:00
Throughputs - December through February: 17 March through May: 26
June through August: 30 September through November: 27
Stack Parameters - Height: 26 Diameter: 2.6 Temperature: 185
Flowrate: 17300 Exit Velocity: 0.0
Boiler Capacity: Space Heat Percentage: 0.0 Release Type: [ ]
Point Level Description: ENGINES #1 - 9

PROCESS INFORMATION (Level 3A) for Point 01

SCC Number: 2-02-002-02 SCC Sequence Number: 01 Last Updated by: JHS on 06/07/1996
SCC Description: INTERNLCOMBUSTION INDUSTRIAL NATURAL GAS RECIPROCATING
Type of Source: Process Percent Sulfur: 0.00 Percent Ash: 0.00 Heat Content: 1000

Process Rate Units: FUEL USE - MIL CU FT
Actual Annual Process Rates: 510.7 Maximum Design Rate: 0.000
O3 Season Daily Process Rate: 1.4
Process Rate Units Code: Confidentiality (0=No,1=Yes) 1
Process Description: RECIP ENGINES 1-9 (FUEL USE)

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: CARBON MONOXIDE (42101) Last Updated by: KTI on 04/11/1996
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [5]
Emission Factor: 130
Annual Emissions: 33 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: 181 lbs per day

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: VOLATILE ORGANIC COMPOUNDS (43104) Last Updated by: KTI on 04/11/1996
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [3]
Emission Factor: 110
Annual Emissions: 28.09 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: 108 lbs per day

PROCESS INFORMATION (Level 3A) for Point 01

SCC Number: 2-02-002-02 SCC Sequence Number: 02 Last Updated by: JHS on 04/17/1996
SCC Description: INTERNLCOMBUSTION INDUSTRIAL NATURAL GAS RECIPROCATING
Type of Source: Process Percent Sulfur: 0.00 Percent Ash: 0.00 Heat Content:

Process Rate Units: OPER HRS
Actual Annual Process Rates: 44140 Maximum Design Rate: 0.000
O3 Season Daily Process Rate: 120.9
Process Rate Units Code: Confidentiality (0=No,1=Yes)
Process Description: ENGINES 1-9 (OPER HRS)

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: SULFUR DIOXIDE (42401) Last Updated by: KTI on 04/11/1996
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [3]
Emission Factor: 0.0073
Annual Emissions: 0.16 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: lbs per day

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: NITROGEN DIOXIDE (42602) Last Updated by: JHS on 07/05/1995
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [5]
Emission Factor: 38.8
Annual Emissions: 856.3 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: 4692 lbs per day

$$\frac{\frac{4692\ LB}{9\ UNITS}}{2000\ LB/T} = 0.26\ T/DAY/UNIT$$

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: VOLATILE ORGANIC COMPOUNDS (43104) Last Updated by: JHS on 06/07/1996
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [5]
Emission Factor: 0.12
Annual Emissions: 2.6 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: 14.5 lbs per day

POINT INFORMATION (Level 2A)

Point ID: 02 Local Point ID: Last Updated by: KTI on 06/27/1995
SIC: 4922
UTM Easting: 625.50 UTM Northing: 4230.60 Latitude: - - Longitude: - -
Operating Schedule - Hours per day: 24 Days per Week: 7 Weeks per year: 52
Start time: 00:00 Ending time: 24:00
Throughputs - December through February: 45 March through May: 31
June through August: 10 September through November: 14
Stack Parameters - Height: 43 Diameter: 11.2 Temperature: 650
Flowrate: 194692 Exit Velocity: 32.8
Boiler Capacity: Space Heat Percentage: 0.0 Release Type: [ ]
Point Level Description: TURBINE

PROCESS INFORMATION (Level 3A) for Point 02

SCC Number: 2-02-002-01 SCC Sequence Number: 01 Last Updated by: KTI on 04/11/1996
SCC Description: INTERNLCOMBUSTION INDUSTRIAL NATURAL GAS TURBINE
Type of Source: Process Percent Sulfur: 0.00 Percent Ash: 0.00 Heat Content: 1000

Process Rate Units: FUEL USE - MIL CU FT
Actual Annual Process Rates: 391.3 Maximum Design Rate: 0.000
O3 Season Daily Process Rate: 1.07
Process Rate Units Code: Confidentiality (0=No,1=Yes) 1
Process Description: TURBINE (FUEL USE)

PLANT INFORMATION (Level 1)

Plant Name: TEXAS GAS TRANSMISSION Last Updated by: JHS on 05/04/1998
Type of Inventory: 4
State: KENTUCKY County: JEFFERSON CO (1920) AQCR: 078
NEDS Plant ID: 0223 Emissions Year: 1997 Local Plant ID:
Street Address: 10327 GASLIGHT WAY City: LOUISVILLE, KY Zip Code: 42301-
City Code: 2380 UTM Zone: 16 UTM Easting: 625.5 UTM Northing: 4230.6
Township/Modeling Grid Code:
SIC Codes - Primary: 4922 Secondary: Tertiary:
Principal Product: NAT GAS Employees: 30 Plant Area: 5.0 acres
Plant Contact: DARRELL MORGAN Telephone Number: (502) 688-6957 Engineer: Stephen M. Taylor
Plant Level Comment:

Notes:

(1) VOC emissions derived from operating hours are formaldehyde.
(formaldehyde emissions are also entered under the A1 HAPS point record)

(2) Emission factor units are lbs/oper hr for the entries under the categories of operating hours.

POINT INFORMATION (Level 2A)

Point ID: 01 Local Point ID: Last Updated by: JHS on 05/04/1998
SIC: 4922
UTM Easting: 625.50 UTM Northing: 4230.60 Latitude: - - Longitude: - -
Operating Schedule - Hours per day: 24 Days per week: 7 Weeks per year: 52
Start time: 00:00 Ending time: 24:00
Throughputs - December through February: 30 March through May: 27
June through August: 21 September through November: 22
Stack Parameters - Height: 26 Diameter: 2.6 Temperature: 185
Flowrate: 17300 Exit Velocity: 0.0
Boiler Capacity: Space Heat Percentage: 0.0 Release Type: [ ]
Point Level Description: ENGINES #1 - 9

PROCESS INFORMATION (Level 3A) for Point 01

SCC Number: 2-02-002-02 SCC Sequence Number: 01 Last Updated by: JHS on 06/07/1996
SCC Description: INTERNLCOMBUSTION INDUSTRIAL NATURAL GAS RECIPROCATING
Type of Source: Process Percent Sulfur: 0.00 Percent Ash: 0.00 Heat Content: 1000

Process Rate Units: FUEL USE - MIL CU FT
Actual Annual Process Rates: 376 Maximum Design Rate: 0.000
O3 Season Daily Process Rate: 2.33
Process Rate Units Code: Confidentiality (0=No,1=Yes) 1
Process Description: RECIP ENGINES 1-9 (FUEL USE)

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: CARBON MONOXIDE (42101) Last Updated by: KTI on 04/11/1996
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [5]
Emission Factor: 130
Annual Emissions: 24.4 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: 111 lbs per day

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: VOLATILE ORGANIC COMPOUNDS (43104) Last Updated by: JHS on 05/19/1997
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [3]
Emission Factor: 110
Annual Emissions: 21.9 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: 100 lbs per day

PROCESS INFORMATION (Level 3A) for Point 01

SCC Number: 2-02-002-02 SCC Sequence Number: 02 Last Updated by: JHS on 04/17/1996
SCC Description: INTERNLCOMBUSTION INDUSTRIAL NATURAL GAS RECIPROCATING
Type of Source: Process Percent Sulfur: 0.00 Percent Ash: 0.00 Heat Content:

Process Rate Units: OPER HRS
Actual Annual Process Rates: 30257 Maximum Design Rate: 0.000
O3 Season Daily Process Rate: 69.1
Process Rate Units Code: Confidentiality (0=No,1=Yes)
Process Description: ENGINES 1-9 (OPER HRS)

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: SULFUR DIOXIDE (42401) Last Updated by: KTI on 04/11/1996
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [3]
Emission Factor: 0.0073
Annual Emissions: 0.33 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: lbs per day

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: NITROGEN DIOXIDE (42602) Last Updated by: JHS on 07/05/1995
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [5]
Emission Factor: 38.8
Annual Emissions: 587.0 tons per year
~~Rule Effectiveness:~~
O3 Season Daily Emissions: 2680 lbs per day

$$\frac{\frac{2680 \text{ LB}}{9 \text{ units}}}{2000 \text{ LB/T}} = 0.15 \text{ T/DAY/UNIT}$$

PROCESS EMISSIONS INFORMATION (Level 3B) for Point 01

Pollutant: VOLATILE ORGANIC COMPOUNDS (43104) Last Updated by: JHS on 06/07/1996
Primary Control Device: [ ]
Secondary Control Device: [ ]
Control Device Efficiency: 0.0 %
Estimation Method: [5]
Emission Factor: 0.12
Annual Emissions: 1.78 tons per year
Rule Effectiveness:
O3 Season Daily Emissions: 8.13 lbs per day

POINT INFORMATION (Level 2A)

Point ID: 02 Local Point ID: Last Updated by: KTI on 06/27/1995
SIC: 4922
UTM Easting: 625.50 UTM Northing: 4230.60 Latitude: - - Longitude: - -
Operating Schedule - Hours per day: 24 Days per week: 7 Weeks per year: 52
Start time: 00:00 Ending time: 24:00
Throughputs - December through February: 30 March through May: 27
June through August: 21 September through November: 22
Stack Parameters - Height: 43 Diameter: 11.2 Temperature: 650
Flowrate: 194692 Exit Velocity: 32.8
Boiler Capacity: Space Heat Percentage: 0.0 Release Type: [ ]
Point Level Description: TURBINE

PROCESS INFORMATION (Level 3A) for Point 02

SCC Number: 2-02-002-01 SCC Sequence Number: 01 Last Updated by: KTI on 04/11/1996
SCC Description: INTERNLCOMBUSTION INDUSTRIAL NATURAL GAS TURBINE
Type of Source: Process Percent Sulfur: 0.00 Percent Ash: 0.00 Heat Content: 1000

Process Rate Units: FUEL USE - MIL CU FT
Actual Annual Process Rates: 636.7 Maximum Design Rate: 0.000
O3 Season Daily Process Rate: 1.45
Process Rate Units Code: Confidentiality (0=No,1=Yes) 1
Process Description: TURBINE (FUEL USE)